Appendix A

Corrections and Clarifications

A. Corrections of Factual Errors Regarding Configuration and Operation of LRPC

1. The DEIS states that the cooling towers at the LRPC are natural draft towers. DEIS at 2-31. The cooling towers at the LRPC are mechanical draft towers. 0018-17

2. The DEIS states that certain water treatment facilities are "next to" the LRPC. DEIS at S-17. Likewise, on Figures S-7 and 2.2-17, the "La Rosita Tertiary Treatment Plant" is shown outside and adjacent to the LRPC. All of these water treatment facilities are within and are part of the LRPC. 0018-18

3. The DEIS repeatedly states that makeup water for the LRPC is taken from the Zaragoza Lagoons. See, e.g., DEIS at 2-41 (Table 2.5-1), 4-13, 4-19. In fact, the makeup water is municipal wastewater (principally sewage) that is taken at the inlet to the lagoons. As a result, the operation of the LRPC not only reduces the pollutant loading to the New River in the water that it diverts from the lagoons, but also improves the effectiveness of the lagoons by eliminating the overloading of their treatment capacity. 0018-19

4. One commenter asserts that the DEIS provides no information on any wastewater treatment process at the power plants that is specifically designed to remove dissolved solids (TDS). In fact, the DEIS does describe the treatment processes at both the LRPC and the TDM plant that result in the removal of TDS -- which are the biological sewage treatment plant and the lime softening clarifiers. See DEIS at 2-33 to 2-34. The final EIS should clarify this point by describing more explicitly the manner in which TDS is removed during these processes. Specifically, in both the biological treatment plant and the lime softening clarifiers, a portion of the compounds that are dissolved in the influent wastewater are precipitated out during the treatment process and are removed as sludge which is disposed of in a landfill.

   Moreover, data regarding the wastewater quality at the TDM plant confirm that these processes result in the removal of dissolved solids. The TDM treatment system contractor took numerous conductivity readings for the raw water, biological treatment system effluent and lime softener effluent for a five-month period after startup. Average conductivity readings for the three sample points were 1960 microS/cm, 1830 microS/cm, and 1600 microS/cm, respectively. Conductivity (specific conductance) is a measure of the conductive dissolved solids content (TDS) of water. The greater the conductivity, the higher the dissolved solids concentration. The DEIS used a TDS concentration for the inflow the TDM plant of 1200 mg/l. Assuming that the measured conductivity value of 1960 microS/cm is equivalent to a TDS concentration of 1200 mg/l (which yields a reasonable TDS to conductivity ratio of 0.61), the derived TDS 018-20

concentrations in the biological system and lime softener effluent streams would be 1116 mg/l and 976 mg/l, respectively. In addition, these figures are even lower than the estimated dissolved solids concentrations that were used to calculate mass of TDS removal. (For the TDM plant, the estimated TDS concentrations in the treated water streams from the biological treatment system and the lime softening process were 1180 mg/l and 1000 mg/l, respectively.) Thus, not only does actual operating experience verify the removal of TDS, it also demonstrates that mass of TDS removed is somewhat higher than what was conservatively calculated in the DEIS. 0018-20 (cont.)

5. The draft EIS states that wastewater effluent from the LRPC would be collected in a sump and then discharged to drainage channel where it eventually combines with the effluent from the Zaragoza Lagoons. DEIS at 2-33. The final EIS should include a more complete description of the configuration of the discharge points and the drainage channel system. The wastewater effluent from the LRPC is discharged into a drainage channel that eventually connects to the Drenaje de Internationale, which is a major drainage channel flowing to the east parallel to the U.S.-Mexico border. The Drenaje de Internationale is part of a large network of drainage channels that carry excess irrigation water from agricultural lands in the vicinity of the power plants. The Drenaje de Internationale empties into the New River just south of the border between Mexicali and Calexico. The point at which the power plants discharge into the drainage channel network is about six miles from the point at which the Drenaje de Internationale eventually empties into the New River. The Drenaje de Internationale carries the combined flows of irrigation runoff, effluent from the LRPC and TDM plant, and effluent from the Zaragoza Lagoons. As a result, the quality of the water entering the New River from the drainage channel reflects the characteristics of this combined flow.[1] 0018-21

6. The DEIS states that wastewater collected from operations at the LRPC is discharged "untreated" to the drainage channel network that empties into the New River. DEIS at S-17. This is not correct. Floor and equipment drains are processed through an oil/water separator and demineralizer regeneration wastes are neutralized in a neutralization tank. In addition, to protect the cooling tower from fouling, each cooling tower system has a sidestream filtration system to remove suspended solids from the circulating water (and, thus, from cooling tower blowdown). 0018-22

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[1] Thus, the attempt by one commenter to contrast the beneficial "diluent" effect of the Zaragoza Lagoon effluent on TDS concentrations in the New River to the adverse effect of the "direct discharge" into the New River of effluent from the power plants is based on a fundamental misconception about the configuration of the discharge facilities for these wastewater streams. At no time does the effluent from the plants discharge directly into the New River prior to being diluted by other flows in the Drenaje de Internationale (including the "low salinity" effluent from the Zaragoza lagoons).

7. One commenter asserts that the cumulative impacts analysis of the EIS must assume the future operation of an additional 600 MW of generating facilities at the LRPC because the BCP transmission line has the capacity to transmit an additional 600 MW of electricity. For the record, there are currently no plans to install any additional generating capacity at the LRPC. 0018-23

B. Other Corrections and Clarifications

1. On page S-26, the DEIS states that EAX plant consumes water at the rate of 4440 acre-ft/yr. The DEIS elsewhere uses the figure of 4940 acre-ft/yr. See, e.g., Tables S-1 and 4.2-1. 0018-24

2. On page 3-22, the DEIS state that the current flow of wastewater entering the Zaragoza lagoons is 27.4 mgd (30,670 acre-ft/yr). This is inconsistent with the figure of 33,200 ac-ft/yr for the flow out of the lagoons which is stated in the following paragraph (and elsewhere in the DEIS). 0018-25

3. Footnote "a" to Table 3.2-4 cites Kasper (2003) as the source of data presented for selenium and total phosphorus. Kasper also is the source for the other data in the table. 0018-26

4. The DEIS states that the concentration of selenium in the lagoon effluent is 0.0011 mg/l. See Tables 3.2-4 and 4.2-2. This figure was calculated by taking the average of all detectable concentrations in lagoon effluent samples. The more commonly accepted convention would have been to use a figure of 50% of the method detection level for samples that in which no selenium was detected. By this method, the average concentration of selenium in the lagoon effluent would be closer to 0.0007 mg/l. 0018-27

5. To calculate the concentration of selenium in the effluent from the LRPC, the DEIS applied a nominal 75% reduction factor to the average selenium concentration in the lagoon effluent. See Table 4.2-2. The LRPC uses lagoon influent, not lagoon effluent. More important, this removal factor should be applied for both the biological sewage treatment plant and the subsequent lime softening process. Using an average concentration of 0.0007 mg/l Se in the raw sewage entering the lagoon, assuming a 75% combined removal through the sewage treatment plant and the lime softener, and using a concentration factor of 4.8 in the LRPC wastewater discharges, we estimate that the selenium concentration in the final effluent from the plant to be 0.0008 mg/l. Attached at Appendix B is a revised table 4.2-2 that shows the estimated selenium removal figures using these revised inputs. 0018-28

6. The DEIS identifies oil- and gas-field brines as a major source of salts "in waters." DEIS at 3-14. It is unclear if this is intended to be a general statement, or a statement about the source of salts in the New River. We are not aware of 0018-29

any oil- or gas-field operations in the area of the New River between Mexicali and the Salton Sea. 0018-29 (cont.)

7. Table 4.2-1 contains a math error. In the "No Action" column, the figure for water discharged from lagoons should be 26,989 ac-ft/yr and the figure for net water delivered to the New River should be 28,260 ac-ft/yr. 0018-30

8. Equation F.8 in Appendix F appears to use an incorrect input to calculate that a period of 0.2 years is required reach equilibrium in response to reduced inflows resulting from power plant operations. Common sense indicates this period should be closer to a year. The text indicates that the new inflow to the Salton Sea with both TDM and LRPC operating would be 1,329,333 ac-ft/yr. At present, inflows to the Sea approximately equal the evaporation rate because the level of the Sea is stable. Thus, multiplying the listed evaporation rate of 5.90 ft/yr by the listed area (234,113 acres) yields a loss due to evaporation of 1,381,267 acre-ft/yr, which should also equal the current inflow. The difference between this inflow figure and the inflow of 1,329,333 acre-ft/yr when both plants are operating is 51,934 acre-ft/yr. This figure is about five time higher than the projected water consumption for the all of the power plants, indicating that the calculated period of 0.2 years is about five times too low. The calculation in Appendix 8 should be redone using the correct flow rates. 0018-31

9. Table 4.2-2 provides no value for the concentration of several pollutants under the "Both Plants Operating" column. Footnote "d" explains that "[d]ischarge from the LRPC and TDM plant occurs at different locations; therefore, no single concentration can be applied to both plants operating." This is not true when the concentrations in the discharge from each plant are equal, as is the case for BOD, COD, phosphorus and selenium. 0018-32

10. Table 9-1, under "Water Resources: (CWA)," states "No NPDES permit required. Other requirements may apply." It is not clear what other Clean Water Act requirements may apply. Certainly, the Clean Water Act does not apply to discharges from the power plants, which are located in Mexico, and which discharge into the New Rive in Mexico. The same is true for TMDLs identified in Table 9-1 as "applicable" to the New River and the Salton Sea. 0018-33

11. Table 9-1, under "Other: Pollution Prevention Act," indicates that the certain release reporting requirements are "potentially applicable." No such requirements apply to the power plants, which are located in Mexico, and it is not clear how such requirements could apply to the transmission lines themselves. 0018-34

APPENDIX B

Table 4.2-1 Water Use for No Plants Operating, No Action, and Proposed Action
(Added columns for EBC Only and EBC & TDM)

Water Use (ac-ft/yr)	No Plants Operating	EBC	TDM	EBC & TDM
Water taken from lagoons	0	2,804	4,372	7,176
Water consumed by plant(s)	0	2,230	3,497	5,727
Water discharged by plant(s) after use	0	574	875	1,449
Water discharged from lagoons	33,200	30,396	28,828	26,024
Net water delivered to New River	33,200	30,970	29,703	27,473
Percent change in water delivered to New River	NA	-6.7	-10.5	-17.3

Table 4.2-2 Projected Annual Operating Parameters
(Added columns for EBC Only and EBC & TDM)

Parameter	No Plants Operating	EBC	TDM	EBC & TDM
Water Volumes				
From lagoons to power plants (ac-ft/yr)	0	2,804	4,372	7,176
Consumed by plant operations (ac-ft/yr)	0	2,230	3,497	5,727
Discharged after use (ac-ft/yr)	0	574	875	1,449
Discharged from lagoons to New River (ac-ft/yr)	33,200	30,396	28,828	26,024
Net volume to the New River (ac-ft/yr)	33,200	30,970	29,703	27,473
Percent change in volume delivered to the New River	NA	-6.7	-10.5	-17.3
TDS				
Concentration in lagoon effluent (mg/l)	1,200	1,200	1,200	1,200
Concentration in discharge water (mg/l)	NA	4,800	4,430	4,577
Concentration load to New River from discharge water (million lbs)	NA	7.5	10.5	18.0
Load to New River from lagoons (million lbs)	108.3	99.2	94.1	84.9
Change in load to New River from lagoons (million lbs)	0.0	-9.1	-14.3	-23.4
Total Load to New River (million lbs)	108.3	106.7	104.6	102.9
Net change in load to New River (million lbs)	0	-1.7	-3.7	-5.4
Percent change in load to the New River	0	-1.5	-3.4	-5.0
TSS				
Concentration in lagoon effluent (mg/l)	59	59	59	59
Concentration in discharge water (mg/l)	NA	5	5	5
Concentration load to New River from lagoons (million lbs)	5.3	4.9	4.6	4.2
Change in load to New River from lagoons (million lbs)	0	-0.45	-0.70	-1.15
Load to New River from plant discharge (million lbs)	NA	0.008	0.012	0.020
Net change in load to New River (million lbs)	0	-0.44	-0.69	-1.13
BOD				
Concentration in lagoon effluent (mg/l)	44	44	44	44
Concentration in discharge water (mg/l)	NA	10	10	10
Load to New River from lagoons (million lbs)	3.97	3.64	3.45	3.11
Change in load to New River from lagoons (million lbs)	0	-0.34	-0.52	-0.86
Load to New River from plant discharge (million lbs)	NA	0.016	0.024	0.039
Net change in load to New River (million lbs)	0	-0.32	-0.50	-0.82
COD				
Concentration in lagoon effluent (mg/l)	162.00	162.0	162.0	162.0
Concentration in discharge water (mg/l)	NA	15.0	15.0	15.0
Load to New River from lagoons (million lbs)	14.61	13.39	12.70	11.46
Change in load to New River from lagoons (million lbs)	0	-1.23	-1.91	-3.15
Load to New River from plant discharge (million lbs)	NA	0.023	0.036	0.059
Net change in load to New River (million lbs)	0	-1.20	-1.87	-3.09
Phosphorus				
Concentration in lagoon effluent (mg/l)	4.3	4.3	4.3	4.3
Concentration in discharge water (mg/l)	NA	1.5	1.5	1.5
Load to New River from lagoons (million lbs)	0.39	0.36	0.34	0.30
Change in load to New River from lagoons (million lbs)	0	-0.03	-0.05	-0.08
Load to New River from plant discharge (million lbs)	NA	0.0023	0.0036	0.0059
Total Load to New River (million lbs)	0.39	0.36	0.34	0.31
Net change in load to New River (million lbs)	0	-0.03	-0.05	-0.08

Table 4.2-2 Projected Annual Operating Parameters
(Selenium - Added columns for EBC Only and EBC & TDM and Revised Existing Columns)

Parameter	No Plants Operating	EBC	LRPC Only	TDM	EBC & TDM	All Plants Operating
Water Volumes						
From lagoons to power plants (ac-ft/yr)	0	2,804	9,015	4,372	7,176	13,387
Consumed by plant operations (ac-ft/yr)	0	2,230	7,170	3,497	5,727	10,667
Discharged after use (ac-ft/yr)	0	574	1,845	875	1,449	2,720
Discharged from lagoons to New River (ac-ft/yr)	33,200	30,396	24,185	28,828	26,024	19,813
Net volume to the New River (ac-ft/yr)	33,200	30,970	26,030	29,703	27,473	22,533
Percent change in volume delivered to the New River	NA	-6.7	-21.6	-10.5	-17.3	-32.1
Selenium						
Concentration in lagoon effluent (mg/l)	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
Concentration in discharge water (mg/l)	NA	0.0008	0.0008	0.0008	0.0008	0.0008
Load to New River from lagoons (lbs)	63.2	57.9	46.0	54.9	49.5	37.7
Change in load to New River from lagoons (lbs)	0	-5.3	-17.2	-8.3	-13.7	-25.5
Load to New River from plant discharge (lb)	NA	1.2	4.0	1.9	3.2	5.9
Total Load to New River (lbs)	63.2	59.1	50.0	56.8	52.7	43.6
Net change in load to New River (lbs)	0	-4.1	-13.1	-6.4	-10.5	-19.6
Percent change in load	0	-6.5	-20.8	-10.2	-16.6	-31.0

Table 4.2-3 Changes in New River Flows Caused By Plant Operations
(Added columns for EBC Only and EBC & TDM)

Physical Parameter	No Plants Operating	EBC	TDM	EBC & TDM
Calexico Gage				
Mean flow (ac-ft/yr)	180,000	177,770	176,503	174,273
Percent change in annual flow	0	-1.2	-1.9	-3.2
Standard deviation on flow	45,827	NA	NA	NA
Change in flow as a percent of standard deviation	0	4.9	7.6	12.5
Westmorland Gage				
Mean flow (ac-ft/yr)	465,180	462,950	461,683	459,453
Percent change in annual flow	0	-0.5	-0.8	-1.2
Standard deviation on flow	30,769	NA	NA	NA
Change in flow as a percent of standard deviation	0	7.2	11.4	18.6

APPENDIX C

sierra research

1801 J Street
Sacramento, CA 95814
(916) 444-6666
Fax: (916) 444-8373

July 29, 2004

Memo To: Sean Kiernan
Intergen

From: Gary Rubenstein

Subject: PM_{10} Emission Rates from Gas Fired Combustion Turbines

This is in response to your request for a summary of our conclusions regarding the PM_{10} emission rates expected from gas fired combustion turbines. These conclusions are based on the results of extensive analysis of PM_{10} test results that we have performed during the last four years, and which were presented during an Air & Waste Management Association (AWMA) conference held in San Diego in March, 2001,[1] and at the ASME/IGTI Turbo-Expo in Atlanta, Georgia in June 2003.[2] Our conclusions have been confirmed as a result of source tests performed on a number of new plant installations in California (and elsewhere) between 2001 and 2004.

It is my professional opinion that F-class turbines, such as those used at the La Rosita Power Complex, can be demonstrated to achieve PM_{10} emission rates of 5 lbs/hr, including both filterable (front-half) and condensable (back-half) particulate matter, when measurements are performed correctly using current U.S. test methods. It is my further opinion that under new test methods currently being developed, the PM_{10} emissions from F-class gas turbines would be more properly measured at levels of 1.0 lb/hr or less. The reasons for my conclusion are presented below.

Over the last 20 years, gas-fired combustion turbines have become the technology of choice for the generation of electric power in the United States. This has resulted in increased attention to the measurement and control of air pollutant emissions from these units. Nearly 20 years ago, it was common to refer to particulate emissions from gas-fired combustion turbines as "negligible," without quantification. However, increases in the size of gas turbine power generation facilities have required that emissions of particulates from these units be quantified and subjected to enforceable permit conditions.

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[1] "Sources of Uncertainty When Measuring Particulate Matter Emissions from Natural Gas-Fired Combustion Turbines", Gary Rubenstein, Sierra Research. Presented to the Air & Waste Management Association, San Diego, California, March 30, 2001

[2] "Gas Turbine Particulate Emissions – Update", Gary Rubenstein, Sierra Research. Presented to the ASME/IGTI Turbo-Expo, Atlanta, Georgia, June 18, 2003.

During the late 1980s and early 1990s, testing of particulate matter emissions from combustion turbines began with increasing frequency. Using test methods designed more than 30 years ago for sources with much higher particulate emission rates, results of source tests for particulates from gas-fired turbines showed significant variability. Since gas turbines have inherently low particulate emission rates, these emissions are not amenable to post-combustion controls. In addition, there has been insufficient study to determine the source of these particulates. As a result, when high results are observed during a source test, the only options available to plant operators and equipment vendors are to perform a retest (and hope for a lower number), or to seek an increase in the allowable emission limit. This, in turn, has led turbine manufacturers to propose higher commercial guarantees in an attempt to protect them from this variability.

To date, we have reviewed the results of 304 particulate source test results from 77 engines produced by various manufacturers and of various sizes. Of these, 284 were tests performed using natural gas as a fuel. We normalized these test results to a nominal turbine output of 180 MW (the nominal output of an F-class combustion turbine) to allow the results to be compared and contrasted. The average particulate measurement reported for the gas-fired tests is 5.99 lbs/MMMbtu (11.4 lbs/hr); the standard deviation of these results is exceedingly high – 12.59 lbs/MMMbtu (23.9 lbs/hr), or 210% of the mean value, which indicates a significant variability in the test results that cannot be explained by differences in equipment or fuel quality. This kind of variability in the test results in turn raises questions about the reliability of the test methodology.

Our review of these data suggested that there were four principal sources of variability in particulate tests of gas turbines. The first is the seemingly random occurrence of particulates of unknown origin in gas turbine exhaust that are larger than 10 microns in size. I use the term "seemingly random" because the incidences of high concentrations of larger particles have not been correlated with any particular type of turbine, operating mode, ambient condition, or other effect. This hypothesis of the presence of larger particles is based on an assessment of the variability in particulates collected in the probe wash portion of USEPA Method 5 (and related) test methods. Since these particles are collected through physical impaction on the interior of the sample collection probe and sample line, they are likely to be larger particles that cannot follow the gas stream as it moves through the sample collection apparatus. The use of a PM_{10} sizer, as is provided for in USEPA Methods 201 and 201a, results in an average reduction in the measured particulate emission rates of about 2 lbs/hr, based on a comparison of tests that did and did not use a PM_{10} sizer.

The second principal source of variability arises from the extreme difficulty in accurately measuring filterable particulate matter that weighs several orders of magnitude less than the filter media used to collect the particulates. Our analysis of the available data indicates that the use of a sample collection time of four hours (or longer) results in an average reduction in the measured particulate emission rates of between 2 and 3 lbs/hr, based on a comparison of tests that used shorter and longer sample collection times.

The third principal source of variability lies in the formation of "artifact" sulfates in the impingers used in EPA Method 5 (and similar methods). The artifact sulfates are most likely to be formed when ammonia-based emission control systems (such as selective catalytic reduction) are used. The artifacts are formed due to the absorption of gaseous ammonia and gaseous sulfur dioxide by the impinger liquids. The sulfates produced by the reaction of these absorbed gases in the impinger liquids are indistinguishable from the sulfates that are actually present in the exhaust gas stream. Methods 5, 8 and 202 are all supposed to simulate near-stack formation of secondary particles in the impinger catch. The problem presented here is whether some of the methods – and, in particular, Methods 5 and 202 – over-state this effect to a significant degree. My conclusion is that they do. Our analysis of the available data indicates that the control of artifact sulfate formation can lead to an average reduction in the measured particulate emission rates of up to 8 lbs/hr, based on a comparison of tests that did and did not control for artifact sulfate formation. Others have reported that use of the optional nitrogen purge provided for in Method 202 can produce results similar to those that we've seen with Method 8; our preliminary use of this alternative technique has confirmed this conclusion.

A fourth source of variability currently under study is related to the organic extract portion of Method 202. The source of this variability is unknown at present, but can result in increased back-half measurements of 10-20 lbs/hr. These increases may be consistent and repeatable for a particular series of tests which occur over a period of several consecutive days, but are not found during retests of the same engines under identical operating conditions. Hypotheses regarding this source of contamination revolve around the presence of trace contaminants in the methylene chloride reagent required to be used during the method and/or the method used to dry the organic samples. In one laboratory experiment performed in 2002, laboratory-quality air was drawn through a Method 202 sampling train, and the organic extract portion of Method 202 produced a visible lacquer-like residue on the drying dishes. In other cases, traces of machining oils present in new sampling probes have been found to contribute to this error.

We also considered the possibility that the variability in test results was due to residual ambient particulate in the inlet air for the combustion turbine. This variable is estimated to result in particulate emissions of 1 lb/hr or less, and thus was considered to be only a second order effect.

Recommendations to reduce the first three areas of uncertainty include the use of a true PM_{10} test method (such as EPA Method 201 or 201A) for the filterable portion of the test to eliminate the effect of random occurrences of large particles; use of four-hour sample collection periods to ensure that a sufficiently large sample is collected relative to the weight of the filter media; and the use of EPA Method 8 for "back-half" measurements to enable the separation of sulfates present in the exhaust stream from artifact sulfates formed in the sample collection apparatus. The Method 8 impingers should be analyzed gravimetrically to ensure that all condensable particulates are measured. In the event the regulatory agency does not approve of the use of USEPA Method 8, USEPA Method 202 should be used with the optional one-hour nitrogen purge. To control the fourth area of uncertainty, a full field blank should be collected for each day of testing, and any observed residues should be analyzed for chemical composition.

With these recommended test procedures, our review of available test results suggested that PM_{10} emissions from current F-class combustion turbines (160-200 MW generating capacity) would be measured to be in the range of 4-5 lbs/hr. In addition to demonstrating a lower, more accurate mean value, the variability in the results can be controlled as well. The mean plus three standard deviation PM_{10} emission rate for F-class turbines is 10-11 lbs/hr.

In June 2001, Calpine had tests performed at its new Sutter Energy Center in northern California, using the recommended test methods discussed above. Those tests, which involved Siemens/Westinghouse 501FD, demonstrated PM_{10} emission rates of well under 9 lbs/hr for each three-test average, based on combined filterable (front-half) and condensable (back-half) measurements. During a second series of tests performed in June 2002, the Sutter gas turbines exhibited PM_{10} levels of up to 29 lbs/hr during one series of tests; these tests were affected by the unexplained variability in the Method 202 organic extract analysis. Subsequent retests performed in October 2002 under identical operating conditions indicated average PM_{10} levels of under 3 lbs/hr.

In August 2001, Calpine had tests performed at the Los Medanos Energy Center (LMEC), also in northern California, and again using the recommended test methods discussed above. Those tests involved General Electric 7FA gas turbines. The PM_{10} levels measured from the LMEC turbines were also well under 9 lbs/hr for each three-test average, again based on combined filterable (front-half) and condensable (back-half) measurements. These results were confirmed in a second set of tests performed in 2002.

Comparable results have been obtained at Calpine's Delta Energy Center (501 FD gas turbines) and Duke Energy's Moss Landing Power Plant (7FA gas turbines), both of which were tested in 2002.

These test results confirm that PM_{10} emission rates from F-class gas-fired combustion turbines will be below 9 lbs/hr when proper measurement techniques are used.

In addition to the work that we have performed in this area, GE Energy and Environmental Research Corporation (GE-EER) has been working under the sponsorship of U.S. Department of Energy, Gas Technology Institute, California Energy Commission, New York State Energy Research and Development Authority, and the American Petroleum Institute on the development of improved techniques for the measurements of particulate matter from gas-fired combustion devices. This work has led to the preliminary development of a dilution-tunnel test method which eliminates the sources of testing variability discussed above. When this method was applied to a 7FA gas turbine equipped with DLN combustors, selective catalytic reduction and an oxidation catalyst, it determined $PM_{2.5}$ emissions of less than 1 lb/hr. The values were nearly 33 times lower than the condensible particulate matter measured concurrently using Method 202. An

ASTM committee has been formed to review this method, and it is expected to be submitted to EPA for approval later this year.

In conclusion, I believe that with the use of proper test methods designed to manage the variability in source test results, as recommended above, F-class gas fired combustion turbines will demonstrate PM_{10} emission rates of approximately 5 lbs/hr. If the new dilution tunnel method is used to measure emissions, I believe that the actual PM_{10} (and/or $PM_{2.5}$) emission rates for F-class gas fired combustion turbines will be demonstrated to be less than 1 lb/hr.

APPENDIX D

Burns Engineering Services Inc.
P.O. Box 272
Topsfield, MA 01983-0272
USA

July 30, 2004

Intergen Energy Inc.
Route 3A
Burlington, MA
Attn: Mr. Sean Kiernan, Project Manager

Subject: Retrofitting of a Parallel Wet-Dry Cooling System to the La Rosita Power Complex (LRPC)

INTRODUCTION

Intergen has retained my firm to provide opinions on the feasibility of the proposal by the Border Power Plant Working Group (BPPWG) to retrofit a Parallel Wet-Dry Cooling System at the LRPC. As a result, I have reviewed the comments submitted by the BPPWG on the Draft Environmental Impact Statement prepared by the U.S. Department of Energy for the Imperial-Mexicali 230-kV Transmission Line. In those comments, the BPPWG recommends that the LRPC be retrofitted with a parallel wet-dry cooling system and provides an estimate of the associated costs and energy penalty[1].

To conduct this review and to develop my opinions, I have relied on the statements contained in the BPPWG letter, descriptions of the above power plants and their existing cooling systems and my engineering knowledge of the subject.

My background qualifications regarding the engineering and operation of power plant cooling systems are briefly summarized in the following few paragraphs.

In 1998, I founded Burns Engineering Services Inc. of Topsfield, Massachusetts and I am its President and Director of Engineering. The company is an engineering consulting firm that specializes in the engineering and improvement of power plant cooling systems. In fact, I have focused on the engineering of power plant cooling systems during the majority of my 40-year plus career. Besides having previously been the cooling system specialist for the Stone and Webster Engineering Corporation, a major architect-engineering company for almost 25 years, I was also formerly employed as Manager of Engineering Development for the Condenser Division of Ingersoll-Rand, a major condenser manufacturer that is now Alstom Power.

I have written more than thirty-five articles and papers related to cooling systems and have given seminars on cooling system equipment throughout the US and for the US DOE in India. In 2001, I gave a lecture to the Cooling Technology Institute on Wet and Dry cooling systems. Currently, I Chair the American Society of Mechanical Engineers (ASME) national Committee on Dry, Air Cooled Steam Condensers, PTC 30.1. I also Chair the ASME Wet Cooling Tower Test Code Committee, PTC 23 and I Chair the ASME national Committee on Steam Surface Condensers, PTC 12.2. I am also currently a Member of the ASME Board on Performance Test Codes. Previously, I was the Secretary and a Member of the Board of the Cooling Tower Institute (Now called the Cooling Technology Institute). In addition, I am an ASME Fellow, a licensed professional engineer in several states and hold an MS in

[1] Powers, Bill; "Border Power Plant Working Group (BPPWG) Comments on Draft Environmental Impact Statement for InterGen's La Rosita Power Complex (LRPC) and Sempra's Termoelectrica de Mexicali (TDM) Transmission Lines", July 12, 2004 letter to Mrs. Ellen Russell of the US DOE, pages 2-4.

Mechanical Engineering from Lehigh University. In 2002, I was privileged to be granted both the ASME Distinguished Service Award and also the ASME Performance Test Codes Medal.

SUMMARY OF OPINIONS

1) On page 2, the BPPWG states "The DEIS dismisses dry cooling (pg. 2-36) as a viable cooling alternative by noting that dry cooling imposes a 10 to 15% efficiency penalty on the steam cycle. This is a misleading statement"[2].

   The DEIS does not dismiss dry cooling but instead correctly identifies a realistic ballpark value of the steam cycle generational losses when served by dry cooling towers. It presents those findings in the same straightforward manner that power plant designers & engineers employ when relating the energy penalty of the cooling system of a combined-cycle plant.

2) On page 3 of their letter, BPPWG states that the "annual average efficiency penalty imposed by dry cooling is estimated at 1.5 percent or less by the California Energy Commission (CEC) for the 520 MW Blythe II project located in a desert environment very similar to that of Mexicali." The BPPWG cites a preliminary CEC staff assessment in support of this statement.

   The basis for the CEC's staff's preliminary estimate of a 1.5% energy penalty is not explained. In my experience, however, the energy penalty associated with dry cooling versus wet cooling is generally in the same 10-15% range cited in the DEIS.

   The BPPWG's comments also suggest that the Blythe project provides a real world demonstration of the practicality of dry cooling at the LRPC. In fact, neither dry cooling nor parallel wet-dry cooling is currently in use at the Blythe project. Blythe I is an existing, operating plant that utilizes wet cooling towers In permitting that facility, the CEC "agreed with the applicant (Caithness-Blythe) that expensive dry cooling was not a financially practical alternative for Blythe"[3]and that "Costly dry cooling, including a hybrid wet/dry system, therefore was unnecessary and would not be imposed". It is known that Blythe II has been proposed as a wet cooling tower. In the case of Blythe II, the Applicant's studies had also determined the engineering and water use conditions would be the same as Blythe I so that costly dry cooling would be unnecessary.

3) On page 3, BPPWG states the 2003 Cooling Technology Institute paper, W*hy Every Air Cooled Steam Condenser Needs a Cooling Tower*, "describes in detail how to construct parallel wet-dry cooling systems...". In fact, the paper does not even include a photograph of the parallel (PAC) wet-dry cooling system installed system, just conceptual estimates of some aspects of the theoretical performance and line drawings of the overall concepts of the parallel wet-dry system. The two authors of the paper are Members of the ASME Air-Cooled Steam Condenser Committee that I Chair. They were both employed by the Hamon Company at the time of the paper. Hamon has never manufactured or installed one of those PAC systems that are advocated by BPPWG.

4) On page 3, BPPWG then goes on to claim without any supporting documentation or related studies that "A highly effective parallel wet-dry cooling system, designed to reduce water… could readily be retrofitted to the LRPC cooling systems." The statement is incorrect. In the entirety of the US, only one small 37 MW power plant (Streeter, Unit 7) located in a cold climate has been retrofitted with such as system. There is simply no industry experience to support the required 10 fold plus retrofit extrapolation from that sole small prototype. BPPWG however presents the 1993 installed 37 MW Streeter station as the example of seasoned industry experience to move forward with a conversion of the steam cycle requirements of the 270 MW steam cycle for LRPC.

[2] Ibid, 1
[3] Docket No. 99-AFC-8

5) On page 3, BPPWG states they have determined the capital cost of the PAC system retrofit that accommodates LRPC as "considerably less than $30 million." That figure has no technical, or engineering validity. There is no costing data presented by BPPWG to substantiate its claims except the "back of the envelope", generic wording shown in their letter. The conversion to a PAC cooling system of the size required for LRPC has never been done before, anywhere. It would require an unprecedented, large-scale engineering and construction project within the two existing power plants. The engineering, the performance tradeoffs, the immense size of an optimized retrofit design, the enormous added auxiliary power, the associated energy penalties, the construction plan and schedule, review of site interferences, the annual price escalation… must all be in place before a credible cost evaluation can be executed.[4] Nowhere however in the BPPWG letter is the detail of these considerably important conversion capital costs or significant cost impacts (energy penalty, O&M costs) discussed even in a preliminary way. As a result, I believe that the BPPWG's figure substantially understates the true costs to retrofit a parallel wet-dry cooling system at the LRPC (even assuming that such a retrofit were technically feasible).

   As one example of the insufficiency of the BPPWG cost, it is well known by the industry that the pressure on steel resources by China has driven the price of structural steel from $365/ton in December 2003 to $546/ton[5] in April 2004-about a 50% increase. Since the design of a PAC consists primarily of fabricated steel, that increase alone would have an appreciable effect on its estimated capital costs; however it is not even mentioned by BPPWG in their July 2004 comments.

6) BPPWG also states: "a number of parallel wet-dry cooling systems are in operation around the world…[6]". Insofar as this statement is meant to imply the use of PAC technology is ordinary or commonplace, it is a gross exaggeration. In fact, the recent GEA PAC installation list shows only a total of just three installations to combined-cycle plants operating in the US and one in Argentina. Of the three combined-cycle plants in the US, only the small one cited by BPPWG –Streeter Station, Unit 7 is a retrofit. It is thus obvious that the PAC technology is in its development stage. As is indicated later in my report, a PAC retrofit to the large LRPC and TMD plants would represent an over 10 fold extrapolation of that technology. A conversion of that size has never been accomplished for many good engineering and cost reasons. The major technical reasons for the existing lack of implementation of the PAC technology are outlined in the next section.

PERSPECTIVES ON DRY COOLING TOWERS

With respect to the retrofit application of direct dry cooling to any requirements at LRPC, it is important to appreciate that a dry cooling tower rejects heat to the atmosphere in much the same way an automobile radiator cools an engine. A great number of large fans, each 25 to 35 ft. in diameter would be used to force cooling air over and through a multitude of finned tube surface and the heat of the steam condensing inside the tubes is transferred through the tubes to the cooling air.

There are three significant distinctions in the heat transfer process that separate wet and dry cooling towers:

The first distinction is that the dry tower transfers the rejected plant heat in proportion to the difference between its operating temperature and the ambient dry bulb temperature. Depending on the relative humidity, the dry bulb temperature can be 15°F to 50°F warmer than the wet bulb temperature and so the dry tower usually produces a warmer return to the plant.

[4] JM Burns et al, *Retrofitting Cooling Towers: Estimates Required to Achieve the Next Level of CWA 316(b) Compliance*, ASME Electric Power Conference, March 2004.
[5] Industrial Water World, May/June 2004 Issue.
[6] Ibid, 1

The second difference is that the evaporative heat transfer process that occurs in wet cooling towers essentially humidifies the cooling air and so only requires about one-third to one-fourth of the air quantity of a dry tower. The consequence of this result is that the airflow which must be pumped by the fans of a dry tower is appreciably more.

The third dissimilarity between wet and dry cooling is that the cooling heat transfer process in a dry cooling tower is much less efficient than that of a wet cooling tower with its main reliance on the evaporative process. The latter makes the corresponding size of the dry cooling equipment enormous.

The above comparative effects between wet and dry cooling towers are large. Whereas at design conditions, the coldest water from a typical large commercial power plant wet cooling tower (serving a combined-cycle station over ~500 MW) may "approach" the local wet bulb temperature to within 8ºF to 15ºF, the temperatures from a dry, air cooled steam condenser of a commercial size usually can only "approach" the local, relatively hotter dry bulb temperatures to within 40ºF to 55ºF. That has a significant negative effect on the steam turbine exhaust pressure. In almost any weather, a dry tower adversely impacts plant generation. In addition, as indicated, everything else being equal, dry cooling towers require:

1) Three to four times the number of wet tower large diameter fans in order to convey sufficient air to the finned tube heat exchangers
2) The greater size and number of fans required use a much greater house load or the current required to operate those fans
3) Dry towers are inherently immense in size, including height

Hence a wet tower is the cost-effective preferable choice except in special circumstances. It is clear that dry cooling towers require extraordinary capital and operating costs when compared to wet cooling towers to achieve essentially the same cooling requirements.

The main benefit of a dry tower is that it does not require any water use except for a very small amount that compensates for condensate pump seal leakage and moisture in the air removal exhaust. Its plume is invisible. It would produce no drift or a water vapor plume. No evaporation occurs and no makeup water or blowdown would be required.

The parallel air-cooled (PAC) system marketed by GEA of San Diego combines a wet and dry cooling tower into one cooling system. That system theoretically provides the advantages of low water consumption and an invisible plume during a cool portion of the year with a reasonable turbine backpressure during the hot weather periods in order to improve the station generation. In this design, a duct on the main turbine exhaust duct carries steam to a direct dry air cooled condenser for the condensation of a proportion of the total exhaust steam flow from the turbine. Because that side duct must deliver the steam efficiently to the dry tower without an appreciable pressure loss, the duct must be very large in cross-section and of a short length. But being close to a large structure like a turbine hall or HRSG produces wind effects on the dry tower that are detrimental to its performance; the larger the tower, often the larger the negative effects. To physically allow the tower and installation of the ducts, a proper operation and reasonably good performance of a dry tower, a careful placement of the wet and dry towers as well as the arrangement of the turbine hall equipment must be developed during the planning and design stage of a plant.

These critical layout & arrangement features of the dry tower are unfortunately not able to be considered for a retrofit to an existing facility as would be required for LRPC.

Of the several thousand power plants in the US today, only one has ever been retrofitted with the above PAC cooling system. That was installed on a small 37 MW size plant in Iowa in 1993 and none have been retrofitted since. In fact, only five of these PAC systems exist in the entire US, all on very small plants, and as indicated, only one was a retrofit. The reason for the dearth of experience with retrofitted PAC technology is simple: the turbine exhaust steam duct that must be retrofitted is very large and so it limits applicability. To put it in perspective, the sole, small 37 MW plant to which the PAC system was retrofitted was comprised of four steam ducts leading from the surface condenser to the dry tower. Each duct was 6 feet in diameter. The engineering, structural support, interference, fit-up and duct installation problems are impractical at a large station like LRPC. For a smaller station like Streeter, the size and complexity is less challenging.

It is the quantity and vacuum of the exhaust steam that sets the size of the retrofit duct rather than the MW generated. If the same PAC system were applied to the LRPC, it would represent an over 10 fold extrapolation of the size of the cited 37 MW dry tower ducts. That would require about forty 6 ft diameter ducts of a total side-to-side dimension of 240 ft to be somehow attached to the steam dome of the existing steam surface condenser that is not even 50 ft in length. In addition, there would be an over 10 fold extrapolation of this single, 11 year old construction experience. Further, the dry tower required for this small 37 MW PAC plant was relatively small due to the small size of the Iowa plant and because the PAC cooling system requirements were less demanding with its colder climate and the appreciably lower annual ambient dry bulb temperatures when compared to Mexicali. In contrast to the 37 MW plant in Iowa, for LRPC to convert to a PAC system, several acres of dry cooling tower would be required. That structure would need to be located close to the plants where its performance would be negatively affected by the vagaries of the wind and its interaction with the plant buildings.

The location of the PAC dry cooling tower would most likely result in interference and recirculation effects as the dry cooling tower would not have been considered in the original plant design, further detracting from the PAC performance.

Because of the unique features of each wet cooling system on every power plant, retrofitting even a wet cooling tower is always considered to be difficult, complex and expensive[7]. But the retrofit application of a parallel air cooled (PAC) cooling system to a large-scale utility power plant is a serious increase in the difficulty and is unprecedented. Any conceptual plan for such a conversion at LRPC would produce significant construction, technical and cost impacts. These technical points were altogether left out by BPPWG.

CONCLUSIONS

In summary, the BPPWG recommendation to consider conversion to a wet-dry cooling system at the large-scale LRPC is impractical without any engineering or construction basis or precedent. Technical concerns associated with the distribution of large amounts of steam, land requirements for the dry tower, additional O&M costs, and excessive energy penalty would make the project infeasible & impractical.

Please feel free to contact me should you have any questions about this report.

Sincerely,

JM Burns, PE
Director of Engineering

[7] Ibid.5